December 2001. In November 2002, the 2002 Notes were issued in the amount of $125 million. The 2002 Notes will mature in November 2003.

In 2002, with rates at the levels to which they were raised in 2001 and with the return of more normal water conditions to the Northwest, the Department's financial results improved considerably. The Department generated net cash flow from operations of $97 million in 2002, which was used to reduce its outstanding short-term debt. Favorable financial results have continued in 2003 in spite of water conditions that have not been as favorable as in 2002. The Department has reduced its operating and capital budgets to offset the effect of sub-normal water conditions on cash flow. Through May 31, 2003, the Department has recorded net income of $26.7 million, compared with $25.4 million in 2002.

In December 2001, the City Council adopted new financial policies which provide that rates will remain at their current levels (unless increased by the City Council or adjusted to pass through changes in Bonneville rates) until all short-term debt obligations have been repaid and cash balances in the Department's operating account have reached the level of $30 million. The Department now projects that this point will be reached in the third quarter of 2004. Retail rates can then be set on the basis of new guidelines that give greater recognition to the increased level of risks that the Department faces, given current conditions in power markets. It is anticipated that when the new financial policies take effect in 2005, over 50 percent of the Department's future capital requirements will be financed from operating revenue.

Pending Litigation Before FERC

In two cases currently before FERC, the City is seeking refunds of amounts paid for electricity. Both cases arose from FERC's investigation of the extremely high prices experienced in the California energy markets beginning in May 2000 and continuing into the summer of 2001, which led FERC to issue an order on July 25, 2001 (the "Order").

The Order required a hearing in one case to determine refunds in the California markets operated by the California Independent System Operator and the California Power Exchange. Hearings have been completed and post-hearings briefs submitted. The Order also required a hearing in the second case to determine whether refunds should be ordered for transactions in the Pacific Northwest markets. In September 2001, the administrative law judge issued proposed findings and preliminary recommendations stating that prices in the Northwest were not unreasonable or unjust and refunds should not be ordered. The City filed a brief urging FERC to reject the recommendations and to recognize that the unreasonable prices in California directly affected prices in the Pacific Northwest. Supplemental briefs and evidence were filed by the City and other parties in the wake of Enron's revelation of market manipulation strategies in California. However, on June 25, 2003, FERC issued an order denying refunds in the Pacific Northwest case. The City currently is preparing a motion for rehearing.

The City also is involved in other legal actions relating to the failure of the California Independent System Operator to pay the Department for power deliveries in the fall of 2000. Finally, the City has filed a request to intervene in a FERC investigation of companies that may have cooperated with Enron in transactions designed to adversely affect the California and West Coast markets.

None of these actions is expected to materially adversely affect the financial condition of the Department.

POWER RESOURCES

Overview of Resources

The Department typically meets the majority of its energy requirements from its own power resources. These include four large and three small hydroelectric facilities which generate 7,117,981 MWh of energy, about 49 percent of the energy available to the Department from its owned and contracted resources, under average water conditions. Output from the Department's hydroelectric plants can vary significantly from year to year due to the variability of water conditions. In calendar year 1997, when water conditions were exceptionally good, hydroelectric output totaled 8,346,762 MWh. Under the drought conditions of calendar year 2001, hydroelectric production fell to 3,941,388 MWh. Water conditions in 2002 were closer to normal, and hydroelectric generation amounted to 6,902,317 MWh, or 47 percent of the total energy available to the Department in that year.

The remainder of the Department's energy requirements are supplied through long-term purchased power contracts and short-term purchases of power in the wholesale market. Purchases of energy from Bonneville provided 31 percent of available energy in 2002, reflecting a substantial increase in purchases from Bonneville under the new power sales contract with Bonneville, which took effect on October 1, 2001. The remaining 22 percent of energy used by the Department in 2002 was provided through long-term contracts with other power providers (16 percent) and through short-term purchases in the wholesale power market (six percent). The average cost of energy available to the Department in 2002 from all sources was $14.88 per MWh, excluding transmission and depreciation. The average cost of power in calendar year 2003 is projected to be $14.07 per MWh.

Under the Pacific Northwest Coordination Agreement (the "Coordination Agreement"), the Department and 15 other public and investor-owned utilities in the Northwest have agreed to coordinate the operation of their power generation systems to maximize the firm capability and reliability of the coordinated system. The Coordination Agreement went into effect in 1965 and will terminate on September 24, 2024. Under the terms of the Coordination Agreement, the firm capability of the generating resources of the parties to the agreement is calculated with reference to a critical period, which is defined as the multi-month period of adverse streamflows of historical record during which the amount of firm load that could be served by the firm resources of the parties to the Coordination Agreement was at a minimum. Water conditions would be expected to be better than those of the critical period about 95 percent of the time.

The table below provides an overview of the Department's power resources.

OWNED AND CONTRACTED POWER RESOURCES IN 2004

	One-Hour Peak Capability (MW)	Energy Available Under Critical Water Conditions (MWh) (1)	Energy Available under Average Water Conditions (MWh) (2)	Year FERC License Expires
Department-Owned Resources				
Boundary	1,055	2,985,408	4,301,738	2011
Gorge	177	864,612	989,167	2025
Diablo	159	733,212	848,083	2025
Ross	360	657,000	852,947	2025
Newhalem	2	13,613	13,613	2027
Cedar Falls (3)	30	47,304	81,833	N/A
South Fork Tolt	17	51,912	51,912	2028
Contract Resources				
Bonneville	1,161 (4)	4,185,022	4,926,669	N/A
Box Canyon	12	79,056	79,056	2005
Priest Rapids	68	302,424	371,070	2005
Columbia Storage Power Exchange	21	-	-	N/A
Grand Coulee Project Hydro Authority	64 (5)	236,863	236,863	2022/2027
High Ross	298 (6)	312,773	312,773	N/A
Lucky Peak	113	249,082	337,322	2030
Metro Cogeneration	1	10,541	10,541	N/A
Klamath Falls	100	744,600	744,600	N/A
State Line Wind Project	50	460,185	460,185	N/A

(1) Critical water conditions represent the lowest sequence of streamflows experienced in the Northwest region over a historical period of record (1929-1978). The firm energy capability of hydroelectric resources is the amount of energy that would be produced under critical water conditions. Actual water conditions would be expected to be better than critical water conditions about 95 percent of the time.

(2) Figures in this column represent the average amount of energy that would be produced over all of the water conditions in the period of record (1929-1978).

(3) The Cedar Falls Hydroelectric Plant is not subject to FERC licensing requirements.

(4) Approximate. Through purchase of the Slice product, the Department is entitled to 4.6676 percent of the actual output of the Federal System (as defined below under "Purchased Power Arrangements—The Bonneville Power Administration"). The Department is also entitled to purchase 135.6 average MW of Block power (as defined below under "Purchased Power Arrangements—Bonneville Power Administration") from Bonneville in 2004.

(5) The Department's 50 percent share of installed capacity.

(6) The Department's contract with the Province of British Columbia provides capacity from November through March in an amount equal to 532 MW minus the actual capacity of the Ross Powerhouse.

Resource Acquisitions

In 1996 the Department completed a Strategic Resources Assessment ("SRA") in which it recommended a strategy of reliance on purchases of power in the wholesale market to fill the gap between loads and resources in the near term. In the first half of 2000 the Department published a Strategic Resource Plan ("SRP") which recommended that the Department pursue a number of alternative power sources and demand-side management options to meet its load requirements beyond 2000. Specifically, the SRP recommended that the Department maximize its purchases of Bonneville power under a new power sales contract that was to take effect on October 1, 2001; purchase as much Bonneville power as possible in the form of the Slice-of-the-System product (the "Slice") (see "Purchased Power Arrangements—The Bonneville Power Administration"); pursue a power sales contract of 100 MW from the Klamath Falls Cogeneration Project to replace power previously supplied by the Centralia Steam Plant (see "Purchased Power Arrangements—Klamath Falls Cogeneration Project"); increase the level of conservation savings to be acquired through 2010 (see "Conservation"); and acquire additional power from non-hydro renewable resources (see "Purchased Power Arrangements—Wind Generation"). The City Council approved the recommendations of the SRP update, and the Department has acquired the recommended resources.

Resource Capabilities and Costs

The following tables show the actual and projected availability and cost of resources that are in the Department's current plan to meet its net energy requirements through 2008. Projections for 2003 take into account actual water conditions through May 2003. Precipitation in the watersheds in which the Department's hydroelectric facilities are located has been about 85 percent of normal in the water year beginning October 1, 2002. As a result, the amount of surplus energy available to the Department in 2003 is now projected to be below normal. Output projected for the years beyond 2003 represent the average output that would be realized over all water conditions experienced in the 1929-1978 period, the period generally used for purposes of regional power planning. The tables contain projections that are based on assumptions about future events. Actual conditions may differ from those assumed, resulting in actual results that vary from those projected.

ENERGY RESOURCES
(MWh)

	Actual			Projected (1)					
	2000	2001	2002	2003	2004	2005	2006	2007	2008
Department-Owned Generation									
Boundary	3,809,267	2,339,590	3,971,940	3,443,552	4,301,738	4,290,778	4,282,263	4,291,122	4,302,673
Gorge	959,800	616,754	1,025,291	887,504	989,167	986,045	985,197	985,236	988,704
Diablo	814,712	477,635	900,255	747,494	848,083	845,102	844,453	844,531	847,398
Ross	741,637	392,922	837,204	716,199	852,947	848,744	846,074	848,590	851,681
Cedar Falls/Newhalem	53,780	74,430	89,422	81,643	95,446	95,125	95,125	95,125	95,446
Centralia (2)	277,103	0	0	0	0	0	0	0	0
South Fork Tolt	44,090	40,057	78,205	50,669	51,912	51,777	51,777	51,777	51,912
Subtotal	6,700,389	3,941,388	6,902,317	5,927,061	7,139,293	7,117,571	7,104,889	7,116,381	7,137,814
Energy Purchases									
Bonneville (3)	1,701,674	2,391,518	4,659,586	4,900,117	4,926,669	4,846,234	5,141,268	5,805,573	5,826,918
Box Canyon	57,746	42,663	43,410	46,858	79,056	45,656	0	0	0
Priest Rapids	363,740	262,188	326,522	311,454	371,070	309,397	45,960	46,000	46,159
CSPE	106,603	102,037	99,348	26,350	0	0	0	0	0
GCPHA	238,987	271,009	248,266	261,786	236,863	236,863	236,863	236,863	236,863
High Ross	296,828	307,738	297,123	296,947	312,773	311,020	309,726	311,474	312,130
Lucky Peak	340,825	188,403	288,848	290,403	337,322	337,233	337,233	337,233	337,322
Metro Cogeneration	7,419	11,915	14,539	14,400	10,541	10,512	10,512	8,760	8,784
Klamath Falls	--	326,104	709,520	655,002	796,780	794,548	383,767	0	0
Wind Resources	--	--	106,493	255,397	460,185	494,014	494,014	494,014	495,367
Seasonal Exchange Received	287,066	395,146	208,538	145,946	109,417	108,604	107,926	108,499	109,496
Wholesale Market Purchases (4)	2,571,228	2,411,210	898,613	962,872	33,811	64,660	61,691	53,701	62,074
Subtotal	5,972,116	6,709,931	7,900,806	8,167,532	7,674,487	7,558,741	7,128,960	7,402,117	7,435,113
Total Department Resources	12,672,505	10,651,319	14,803,123	14,094,593	14,813,780	14,676,312	14,233,849	14,518,498	14,572,927
Minus Offsetting Energy Sales:									
Firm Energy Sales and Marketing Losses (5)	249,321	310,670	396,862	195,546	470,765	500,240	525,999	528,582	526,428
Out of System Sales (6)	96,399	15,956	0	0	0	0	0	0	0
Seasonal Exchange Delivered	269,030	376,950	231,650	127,830	90,846	90,623	90,623	90,329	90,580
Wholesale Market Sales	2,023,060	468,827	4,647,945	4,425,908	4,655,826	4,384,676	3,713,090	3,788,301	3,672,456
Total Net Energy Resources (7)	10,034,695	9,478,916	9,526,666	9,345,309	9,596,343	9,700,773	9,904,137	10,111,286	10,283,463

Footnotes to Table:

(1) Projections for 2003 are based on actual water conditions through May 2003. Projections for the 2004-2008 period assume average water conditions.

(2) The Centralia Steam Plant was sold in May 2000.

(3) From 1996 through September 30, 2001, the amount of power purchased under the Bonneville contract was limited to 195 average MW. Beginning on October 1, 2001, energy from Bonneville is based on the new Block and Slice Power Sales contract.

(4) Purchases to compensate for low water conditions and to make up the difference between loads and resources. In 2000 and 2001, the Department's purchases of power in the wholesale market were unusually large, due to poor water conditions.

(5) Energy provided to Public Utility District No. 1 of Pend Oreille County under Article 49 of the Boundary Project's FERC license and to compensate the PUD for the Boundary Project's encroachment on Box Canyon. From 2002 through 2008, figures on this line also include incremental losses due to expanded activity in the wholesale market.

(6) Energy delivered to Nordstrom facilities in California.

(7) Firm energy required in the Department's service area.

COST OF POWER SUPPLY
($000)

	Actual			Projected					
	2000	2001	2002	2003	2004	2005	2006	2007	2008
Wholesale Market Purchases (1)	$ 212,402	$ 518,782	$ 23,154	$ 22,287	$ 973	$ 1,860	$ 1,596	$ 1,673	$ 2,006
Other Power Purchases:									
Bonneville (2)	$ 34,443	$ 66,824	$ 134,805	$ 158,472	$ 147,607	$ 155,187	$ 170,277	$ 198,654	$ 194,019
Box Canyon	998	1,183	1,052	1,042	1,068	633	0	0	0
Priest Rapids	2,136	2,303	2,326	2,551	2,618	2,520	1,734	1,712	1,686
GCPHA	8,406	8,465	7,314	4,206	4,845	2,171	2,225	2,281	2,338
CSPE	0	0	0	0	0	0	0	0	0
High Ross	13,342	13,353	13,358	13,366	13,374	13,385	13,392	13,399	13,406
Lucky Peak	16,985	15,978	12,364	12,661	17,670	17,658	17,712	10,788	4,549
Metro Cogeneration	238	381	1,001	390	390	400	409	419	429
Klamath Falls	0	18,460	39,680	40,713	40,202	42,946	21,662	0	0
State Line Wind Project	0	0	6,474	10,787	18,215	19,631	19,631	19,631	19,685
Int and Ex of Wind Resources	0	0	2,417	5,245	5,346	5,429	5,516	5,604	5,703
Seasonal Exchange Received	6,287	27,964	5,944	4,598	3,546	3,607	3,672	3,778	3,901
Other Servides	0	10,094	1,866	5,000	5,120	5,251	5,379	5,510	5,652
BPA Billing Credits (3)	(3,531)	(3,713)	(3,067)	(3,740)	(3,705)	(3,668)	(3,520)	(3,479)	(3,429)
Subtotal	$ 79,305	$ 161,292	$ 225,534	$ 255,293	$ 256,296	$ 265,148	$ 258,087	$ 258,297	$ 247,938
Production:									
Centralia (4)	$ 7,274	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Hydro Projects (5)	18,611	17,012	18,546	19,584	20,239	21,109	22,221	22,999	23,655
Control and Dispatch	5,285	6,065	6,282	6,607	6,841	7,010	7,174	7,343	7,525
Subtotal	$ 31,170	$ 23,077	$ 24,829	$ 26,191	$ 27,080	$ 28,118	$ 29,395	$ 30,342	$ 31,180
Total Power Supply Expense	$ 322,878	$ 703,151	$ 273,517	$ 303,770	$ 284,349	$ 295,126	$ 289,079	$ 290,312	$ 281,124
Minus Offsetting Power Revenue:									
Wholesale Power Sales	$ 103,082	$ 73,899	$ 112,796	$ 150,386	$ 144,997	$ 137,230	$ 116,695	$ 125,981	$ 126,561
Other Power Sales (6)	5,050	41,573	18,995	21,894	27,275	27,028	31,731	32,697	33,257
Net Cost of Power	$ 214,746	$ 587,679	$ 141,727	$ 131,490	$ 112,077	$ 130,869	$ 140,652	$ 131,634	$ 121,306
Total Energy Requirement (MWh)	10,034,695	9,478,916	9,526,666	9,345,309	9,596,343	9,700,773	9,904,137	10,111,286	10,283,463
Average Unit Cost (Dollars/MWh) (7)	$ 21.40	$ 62.00	$ 14.88	$ 14.07	$ 11.68	$ 13.49	$ 14.20	$ 13.02	$ 11.80

Footnotes to Table:

(1) Purchases to compensate for low water conditions and to make up the difference between loads and resources. Excludes wheeling costs. In 2000 and 2001, the Department purchased unusually large amounts of power in the wholesale market at high prices due to poor water conditions.

(2) From 1996 through September 30, 2001, the amount of power purchased under the Bonneville contract was limited to 195 average MW. Beginning on October 1, 2001, the cost of power from Bonneville is based on the new Block and Slice Power Sales contract. The forecast assumes the CRAC adjustments projected by Bonneville. Effective October 1, 2006, Block purchases from Bonneville are assumed to increase by 114.4 MW under the terms of the power sales contract. See "Power Resources—Purchased Power Arrangements—Bonneville Power Administration."

(3) Billing credits received from Bonneville for the South Fork Tolt Project.

(4) The sale of the Centralia Steam Plant was completed in May 2000.

(5) Includes operation and maintenance costs only.

(6) Includes conservation and renewal credits under the power sales contract with Bonneville, the recognition of payments from Bonneville for the purchase of conservation savings, revenue from the provision of integration and exchange services related to the State Line Wind Project, revenue related to contracts with Grant County PUD for Priest Rapids power beginning in 2005, the valuation of energy delivered under seasonal exchanges and basis sales, revenue from deliveries of energy to Pend Oreille PUD pursuant to Article 49 of the Boundary Project license, and other energy credits.

(7) Average cost of power supplied to service area customers after recognizing the net revenue or cost associated with wholesale power sales and purchases.

The Department's Resources

Boundary Hydroelectric Plant. The Boundary Project is located on the Pend Oreille River in northeastern Washington near the Canadian and Idaho borders, approximately 250 miles from Seattle. The plant was placed in service in 1967. It has a one-hour peak capability of 1,055 MW and expected energy output of 4,301,738 MWh in 2004 under average water conditions. The Boundary Project is operated under a Federal Energy Regulatory Commission ("FERC") license which expires on October 1, 2011. The Department plans to apply for renewal of its Boundary license. The most recent FERC-mandated independent safety inspection in August 2000 concluded that the dam facilities were in good condition.

The Boundary Project's FERC license requires that up to 48 MW of the Boundary Project's capacity be assigned, at cost, to Public Utility District No. 1 of Pend Oreille County ("Pend Oreille PUD"). Due to Pend Oreille PUD's increasing loads and other contractual requirements, the amount of Boundary Project power assigned to Pend Oreille PUD is expected to increase from its present 32 MW to the maximum allowable amount of 48 MW in August 2005.

For a discussion of the impacts of fisheries issues on this facility, see "Environmental Matters—Endangered Species Act Issues." Encroachment of British Columbia Hydro and Power Authority's ("B.C. Hydro") Seven Mile Project on the Boundary Project is discussed below under "Ross, Diablo and Gorge Hydroelectric Plants."

Ross, Diablo and Gorge Hydroelectric Plants. The Ross, Diablo and Gorge hydroelectric plants are located on a ten-mile stretch of the Skagit River above Newhalem, Washington, approximately 80 miles northeast of Seattle. Power is delivered to the Department's service area via two double-circuit Department-owned transmission lines. The Ross Plant, located upstream of the other two projects, has a reservoir with usable storage capacity of 1,052,000 acre-feet. Because the Diablo Plant, with usable storage capacity of 50,000 acre-feet, and the Gorge Plant, with usable storage capacity of 6,600 acre-feet, are located downstream from the Ross Dam, their operation is coordinated with water releases from the Ross Reservoir and the three plants are operated as a single system. The combined one-hour peak capability of the three plants is 696 MW. Expected energy output in 2004 under average water conditions is 2,690,197 MWh.

These plants form the Skagit Hydroelectric Project and are licensed as a unit by FERC. FERC-required independent inspections of the Skagit Project in 2002 revealed no deficiencies. In 1995, FERC issued a new 30-year license for operation of the Skagit Project. As a condition of the new license, the Department has taken and will continue to take various mitigating actions relating to fisheries, wildlife, erosion control, archeology, historic preservation, recreation, and visual quality issues.

Although the original plans for the Skagit Project had included raising the height of Ross Dam by 122.5 feet to maximize the hydroelectric potential of the plant, the Canadian province of British Columbia (the "Province") protested on environmental grounds. After a protracted period of litigation and negotiation, an agreement (the "High Ross Agreement") was reached under which the Province agreed to provide the Department with power equivalent to the planned increase in the output of the Ross Plant in lieu of the Department's construction of the addition for 80 years commencing in 1986. The agreement is subject to review by the parties every ten years. The most recent review, concluded in 1998, did not result in any changes to the agreement.

The Department's annual payments to the Province include a fixed charge of $21.8 million annually through 2020, which represents the estimated debt service costs that would have been incurred had the addition been constructed and financed with bonds. In 2000, the Department began amortizing the remaining annual $21.8 million payments over the period through 2035. Payment of equivalent maintenance and operation costs and certain other charges began in 1986 and will continue for 80 years. The energy delivered under this agreement in 2004 is expected to amount to 312,773 MWh. One-hour peak capability is 150 MW from April through October; from November through March, one-hour peak capability is equal to 532 MW minus the actual peak capability of the Ross Plant, given actual reservoir elevations behind Ross Dam.

If the Province discontinues power deliveries, the High Ross Agreement provides full authority to the Department to proceed with the originally proposed construction and obligates the Province to return to the Department sufficient funds to permit the Department to increase the height of Ross Dam and make other improvements as originally proposed. This obligation has been guaranteed by the Government of Canada.

As authorized in the High Ross Agreement, B.C. Hydro increased the reservoir elevation of its Seven Mile Project on the Pend Oreille River in the spring of 1988, thereby extending its reservoir across the international border to the tail-race of the Boundary Project. An 80-year contract between the City and B.C. Hydro was signed in 1989 to provide compensation to the Department for the encroachment of Seven Mile Reservoir on the Boundary Project.

Cedar Falls Hydroelectric Plant. The Cedar Falls Hydroelectric Plant ("Cedar Falls"), built in 1905, is located on the Cedar River, approximately 30 miles southeast of Seattle. Cedar Falls was constructed before the adoption of the Federal Water Power Act of 1920 and is not subject to licensing by FERC. Cedar Falls power is delivered through an interconnection with Puget Sound Energy. The one-hour peak capability of the plant is 30 MW. Expected energy generation in 2004 under average water conditions is 81,833 MWh.

Newhalem Hydroelectric Plant. The Newhalem Hydroelectric Plant ("Newhalem"), located on Newhalem Creek, a tributary of the Skagit River, was built in 1921 to supply power for the construction of the Skagit Project. The plant was rebuilt and modernized in 1970. It is operated under a FERC license which expires January 31, 2027. The plant's power is delivered over Department-owned transmission lines. The one-hour peak capability of the plant is 0.5 MW. Expected energy generation in 2004 under average water conditions is 13,613 MWh.

South Fork Tolt River Hydroelectric Plant. The South Fork Tolt River Hydroelectric Plant (the "Tolt Project") was placed in commercial operation in 1995. The Tolt Project operates under a 40-year FERC license which expires in 2028. The one-hour peak capability of the installed unit is 16.8 MW. Expected energy production from the Tolt Project is 51,912 MWh. To reduce its cost of power from the Tolt Project, the Department entered into a Billing Credits Generation Agreement with Bonneville in 1993, under which Bonneville makes payments to the Department that have the effect of making the cost of power from the Tolt Project approximately equal to the cost of equivalent power from Bonneville. Payments to the Department under the agreement commenced in 1996 and are expected to amount to $3.7 million in 2003.

Purchased Power Arrangements

In 2002, the Department purchased approximately 47 percent of its total available system energy from other utilities in the region, including Bonneville, under long-term purchase contracts. Some of these agreements with other utilities provide that the Department is obligated to pay its share of the costs of the generating facilities providing the power, including debt service on bonds issued to finance construction, whether or not it receives any power. The Department has covenanted to treat payment of such costs as part of its purchased power expense and includes such costs in its operating and maintenance expenses.

The Department has in the past and may in the future purchase power under the Western Systems Power Pool Agreement and the Block and Slice Power Sales Agreement described immediately below. Those agreements include an obligation on the part of the Department to post collateral contingent upon the occurrence or nonoccurrence of certain future events within the control of the Department, such as future credit ratings or payment defaults. The Department also has entered, and may in the future enter, into agreements that include an obligation on the part of the Department to make payments or post collateral contingent upon the occurrence or nonoccurrence of certain future events that are beyond the control of the Department, such as future changes in gas prices. Such obligations may be characterized as maintenance and operation charges, and thus would be payable from Gross Revenues of the Light System prior to the payment of debt service.

The Bonneville Power Administration. Bonneville markets power from 30 federal hydroelectric projects, from several non-federally-owned hydroelectric and thermal projects in the Pacific Northwest and from various contractual rights with installed peak generating capacity of 24,080 MW and a firm energy capability of approximately 8,500 average MW (the "Federal System"). These projects are built and operated by the United States Bureau of Reclamation (the "Bureau") and the United States Army Corps of Engineers (the "Corps") and are located primarily in the Columbia River basin. The Federal System currently produces approximately 45 percent of the region's energy requirements. Bonneville's transmission system includes over 15,000 circuit miles of transmission lines, provides about 75 percent of the Pacific Northwest's high-voltage bulk transmission capacity and serves as the main power grid for the Pacific Northwest. Its service area covers over 300,000 square miles and has a population of about ten million. Bonneville sells electric power at cost-based wholesale rates to more than 130 utility, industrial and governmental customers in the Pacific Northwest. Bonneville also sells power directly to eight industrial customers in the region. Bonneville is required by law to give preference to government-owned utilities and to customers in the Northwest region in its wholesale power sales.

A 1982 contract with Bonneville entitled the Department to purchase power from Bonneville in amounts equal to the difference between the Department's load and the firm generating capability of its owned and contracted resources. Effective August 1, 1996, this contract was amended to limit the amount of power purchased from Bonneville to 195 average MW in each operating year through September 30, 2001. This lower level of purchases from Bonneville was considerably less than the difference between the Department's load and firm resources. For the remaining term of the contract, the Department filled this gap with purchases of power in the wholesale market.

A Block and Slice Power Sales Agreement with Bonneville covers purchases of power for the ten-year period beginning October 1, 2001. Under the contract, power is delivered in two forms: a shaped block (the "Block") and a Slice. Through the Block product, power is delivered to the Department in monthly amounts shaped to the Department's monthly net requirement, defined as the difference between the Department's projected monthly load and the resources available to serve that load under critical water conditions. The original contract provided for delivery of 163.8 average MW annually as a Block for the period from October 1, 2001, through September 30, 2006, and 278.2 average MW from October 1, 2006, through September 30, 2011. Under the Slice product, the Department receives a fixed 4.6676 percent of the actual output of the Federal System and pays the same percentage of the actual costs of the system. Payments for the Slice product are subject to an annual true-up adjustment to reflect actual costs. True-up payments are made in three equal monthly amounts in the first half of the year following the federal fiscal year to which the payments apply. Power available under the Slice product varies with water conditions, federal generating capabilities and fish and wildlife restoration requirements. Under the most recent estimates of the capability of the Federal System, energy available to the Department through the Slice product is expected to average 426 average MW over all water conditions. Under critical water conditions, the Slice product would provide 334 average MW of energy.

Subsequent to the signing of the Block and Slice contract, the amount of energy to be delivered to the Department by Bonneville has undergone two modifications. In response to Bonneville's request that its customers temporarily reduce their purchases of power from Bonneville, the Department agreed to a reduction of about 24 average MW in the Slice product for the period from October 1, 2001, through March 31, 2002, and a reduction of about 74 average MW for the period from April 1, 2002, through September 30, 2002. In February 2002 Bonneville agreed to purchase from the Department conservation savings expected to be achieved over the period from October 1, 2001, through September 30, 2003. Conservation savings were estimated at 9.8 average MW for the twelve-month period beginning October 1, 2001, and an additional 9.3 average MW for the subsequent twelve-month period. Bonneville agreed to pay the Department $27 million for these savings. The amount of energy to be delivered to the Department as a Block was reduced by 9.8 average MW for the period from October 1, 2001, through September 30, 2002, and by 19.1 average MW for the period from October 1, 2002, through September 30, 2011, to recognize the cumulative effect of the conservation savings on the Department's load. Bonneville has signed a letter of intent in which it has indicated its intention to purchase additional conservation savings in the amount of 7.25 average MW in each of the three federal fiscal years beginning October 1, 2003, 2004 and 2005. The Department's financial forecast assumes that the amount of energy available through the Block product will be reduced by the amount of the additional conservation savings purchased by Bonneville in each of the three federal fiscal years. As a result of these changes in the amounts of energy to be delivered under the contract, the total amount of power available through the contract under critical water conditions is estimated to be

431.6 average MW for the period from October 1, 2003, through September 30, 2004; 460.9 average MW from October 1, 2004, through September 30, 2006; and 571.6 average MW from October 1, 2006, through September 30, 2011. Under average water conditions, an additional 92 average MW of energy would be available through the Slice product.

In May 2000 Bonneville issued a Record of Decision establishing fees and charges effective October 1, 2001, at levels that were slightly higher than Bonneville's then current rates. The ROD included a Cost Recovery Adjustment Clause ("CRAC") which authorized Bonneville to increase its power rates in order to deal with a number of contingencies that might affect adversely its financial condition.

Increases in Bonneville power rates under the CRAC are authorized under three circumstances. First, a Load-Based CRAC adjustment is authorized to cover the additional cost of purchasing power in the wholesale market to serve increases in demand from Bonneville customers that cannot be accommodated by the Federal System. Second, a Financial-Based CRAC can be imposed if higher than expected market prices cause Bonneville's accumulated net revenues to fall below a threshold level. Finally, a Safety-Net CRAC is authorized in any year in which Bonneville projects that there is a less than 50 percent probability that it will be able to pay all of its financial obligations, including its debt service payments to the U.S. Treasury. The Load-Based CRAC applies to both the Block and the Slice products and can be adjusted at six-month intervals; the Financial-Based CRAC and the Safety-Net CRAC apply only to Block purchases. Bonneville used its authority under the Load-Based CRAC to increase rates by 46 percent, effective October 1, 2001. The Load-Based CRAC adjustment was subsequently changed to 39 percent on April 1, 2002, 32 percent on October 1, 2002, and 39 percent on April 1, 2003. A Financial-Based CRAC adjustment of 11 percent was imposed on October 1, 2002. Bonneville has proposed that a Safety-Net CRAC adjustment be implemented later in 2003. Discussions with Bonneville's customers as to the size of the Safety-Net CRAC adjustment are currently in progress. The Department's financial forecast assumes that a Safety-Net CRAC adjustment of 14 percent will take effect on October 1, 2003.

The Department is required by ordinance to pass through to its customers the effect of changes in Bonneville's rates under the various CRAC provisions. See "The Department—Retail Rates." No further action by the City Council is required to pass through Bonneville CRAC adjustments. The Department passed through the effect of Bonneville's October 1, 2001, Load-Based CRAC adjustment by increasing energy charges for all non-low-income customers by $0.0055 per kWh, effective October 1, 2001. Bonneville's subsequent rate adjustments have been passed through to the Department's non-low-income customers through a reduction of $0.0007 per kWh effective April 1, 2002, and an increase of $0.0008 per kWh effective April 1, 2003. In each instance, rates for low-income customers were increased by one-half of the amount of the increase for other rate classes.

Bonneville has projected that the following Load-Based CRAC adjustments will be required in the period through September 30, 2006:

	Block	Slice
October 1, 2003, through March 31, 2004	21%	22%
April 1, 2004, through September 30, 2004	31	32
October 1, 2004, through March 31, 2005	26	27
April 1, 2005, through September 30, 2005	30	31
October 1, 2005, through March 31, 2006	27	28
April 1, 2006, through September 30, 2006	30	31

The Department's financial forecast assumes that the Load-Based CRAC adjustments projected by Bonneville will take effect. In addition, the Department has assumed that the sum of the Financial-Based CRAC and the Safety-Net CRAC will equal 25 percent from October 1, 2003, through September 30, 2006, and that the Department will be required to make Slice true-up payments to Bonneville in the following amounts:

2004	$ 5,156,250
2005	11,952,500
2006	15,675,000
2007	13,818,750
2008 through 2011	9,000,000

The Department's forecast of revenue from retail power sales assumes that the effects of Bonneville's CRAC adjustments will be passed through to the Department's non-low-income retail customer classes through a decrease of $0.0004 per kWh effective from October 31, 2003, through December 31, 2004. The rate reduction for low-income customers is assumed to be $0.0002 per kWh. Beginning in 2005, when the Department is assumed to set new retail rates pursuant to the financial policies adopted by the City Council in December 2001, the projected costs of the Bonneville contract, including the projected effect of CRAC adjustments, are assumed to be included in the revenue requirements on which rates are based.

While the Department has made the assumptions described above regarding the actual cost and amounts of energy available through the Slice product and the level of Bonneville rates, including the additional charges levied pursuant to the CRAC, each of these factors is subject to uncertainty. Actual prices and quantities may differ from the Department's assumptions. The Department addressed the uncertainties associated with its higher level of Bonneville purchases, and particularly the uncertainties related to the nonfirm component of the Slice product, in its review of financial policies in 2001. See "The Department—Financial Policies."

Energy Northwest (formerly known as the Washington Public Power Supply System). The City is a member of Energy Northwest, a municipal corporation and joint operating agency organized under State law that currently has, as members, ten public utility districts and three municipalities, all located within the State. Energy Northwest has the authority to acquire, construct and operate plants, works and facilities for the generation and transmission of electric power.

Energy Northwest was engaged in the construction of five nuclear generating facilities termed Projects Nos. 1, 2, 3, 4, and 5. Project No. 2 was placed in commercial operation in December 1984 and the other projects were terminated in the 1980s. Pursuant to separate Net Billing Agreements with Energy Northwest and Bonneville with respect to Projects Nos. 1, 2 and 3 (the "Net Billed Projects"), the Department is obligated unconditionally to pay Energy Northwest its pro rata share of the total annual costs of the Net Billed Projects, including debt service. The payments are required to be made whether or not construction is completed, delayed or terminated, or operation is suspended or curtailed. Payment by Bonneville to Energy Northwest of the Department's share of its total annual cost of the Net Billed Projects is made by a crediting arrangement whereby Bonneville credits against amounts that the Department owes Bonneville for the purchase of wholesale power an amount equal to the Department's share of the total annual cost of each Net Billed Project. The agreements provide that the Department purchase from Energy Northwest and, in turn, assign to Bonneville a maximum of 8.605 percent, 7.193 percent and 5.043 percent of the capability of Projects Nos. 1 and 2 and Energy Northwest's ownership share of Project No. 3, respectively. The Department's respective shares may be increased by not more than 25 percent upon default of other public agency participants. To the extent the Department's share of such annual costs exceeds amounts owed by the Department to Bonneville, Bonneville is obligated, after certain assignment procedures, to pay the amount of such excess to the Department as reimbursement or to Energy Northwest directly, but only from funds legally available for that purpose.

Under the Net Billing Agreements, the Department's electric revenue requirements are not affected directly by the cost of completion or termination of the Net Billed Projects, but such revenue requirements may be affected to the extent that the costs of such Projects result in increases in the wholesale power rates of Bonneville. Bonneville has been paying principal of and interest on Project No. 1 revenue bonds since 1980, on Project No. 2 revenue bonds since 1977 and on Project No. 3 revenue bonds since 1982. Bonneville, in projecting its revenue requirements and wholesale power rates, includes in its estimate the principal of and interest on those bonds issued and projected to be issued and Energy Northwest's operating expenses for the Net Billed Projects.

Klamath Falls Cogeneration Project. An October 2000 agreement with the City of Klamath Falls, Oregon, provides for the purchase of energy and capacity from the Klamath Falls Cogeneration Project, a 500 MW cogeneration facility consisting of a combined-cycle combustion turbine fueled by natural gas. Under the terms of the contract, the Department will receive 100 MW of capacity from the project beginning on July 28, 2001, the project's on-line date, through June 30, 2006, with an option to renew the contract for an additional five years. The Department expects to receive 796,780 MWh of energy from the plant in 2004.

The City of Klamath Falls has contracted with PacifiCorp Power Marketing, Inc. for management of the plant's operations. PPM is also responsible for providing fuel for the plant. Power from the plant is transmitted to the Department's service area over the Department's share of the Third AC Intertie and the Bonneville system. The Department may elect to displace all or a portion of the energy it is entitled to receive from the Klamath Falls Cogeneration Project in any given month. Payment for power consists of a fixed capacity charge and variable charges for the cost of fuel, which will be based on a published index of gas prices in Alberta, Canada, and for operations and maintenance costs. The cost of power under the contract is expected to average approximately $53 per MWh through June 30, 2006. The actual cost of power may vary from the projected level due to, among other factors, variability in the price of natural gas.

Lucky Peak Hydroelectric Power Plant. The Lucky Peak Hydroelectric Power Plant ("Lucky Peak") was developed by three Idaho irrigation districts and one Oregon irrigation district (the "Districts") and began operation in 1988. Its FERC license expires in 2030. The plant is located on the Boise River, approximately ten miles southeast of Boise, Idaho, at the Lucky Peak Dam and Reservoir. The rated capability of the three generating units at the plant is 101 MW. Energy generation in 2004 under average water conditions is expected to be 337,322 MWh. Since generation is concentrated in the summer months, the plant has no peak capability during the Department's winter peak period.

The Department entered into a 50-year power purchase and sales contract in 1984 with the Districts under which the Department will purchase all energy generated by Lucky Peak, in exchange for payment of costs associated with the plant and royalty payments to the Districts. The Department also signed a transmission services agreement with Idaho Power Company ("Idaho Power") to provide for transmission of power from Lucky Peak to a point of interconnection with the Bonneville system. The Department has contracted to sell the entire net output of the plant for the period from May 1, 2003, through November 30, 2004, at a price equal to the Dow Jones Mid-Columbia Index plus $3.25 per MWh.

Priest Rapids Hydroelectric Plant. Under an agreement effective through October 2005, the Department receives eight percent of the output of the Priest Rapids Hydroelectric Plant ("Priest Rapids"), owned and operated by Public Utility District No. 2 of Grant County ("Grant PUD"). The Priest Rapids facility has an installed capacity of 855 MW, upgraded from 835 MW by FERC in 1998 due to rewinding of three generators. The Department's share of the development's one-hour peak capacity is 68 MW and its share of output in 2004 under average water conditions is expected to be 371,070 MWh.

In 1995, certain Idaho and Snake River cooperatives filed a complaint with FERC in which they sought entitlement to allocation of power from Priest Rapids under any new license. FERC ruled in 1998 that 70 percent of the project's output would be allocated to the new licensee, with the remaining 30 percent available for purchase pursuant to market-based principles by entities in the broad seven-state Northwest region, while giving certain Idaho cooperatives and the current power purchasers a priority right. FERC also issued an order permitting any entity, not just Grant PUD or another Washington public agency, to file a competing license application. These proceedings could impact the amount of power generated at Priest Rapids and the Department's allocation of power upon expiration of the current contract. See "Environmental Matters—Endangered Species Act Issues."

Contracts executed in March 2002 with Grant PUD provide for the allocation of power and other benefits from the Priest Rapids and Wanapum Projects to the Department over the period from November 1, 2005, through the end of the new FERC license period for the two projects. Under the terms of these contracts the Department expects to purchase 45,656 MWh of firm and nonfirm power from Grant PUD in calendar year 2006 at a cost of $347,000. The amount of power available from Grant PUD will decline over time as the PUD's load, and its claim on the projects' output, increases. In addition, in 2006 the Department expects to realize $3.0 million in net revenue from the sale of the 30 percent share of the projects' output that will be sold pursuant to market-based principles in the seven-state Northwest region under the terms of the FERC order. The Yakama Indian Nation has filed a petition with FERC challenging the new contracts signed by Grant PUD.

Columbia Storage Power Exchange. The Department is one of 41 public and private utilities that, with Bonneville, operated under exchange agreements with the Columbia Storage Power Exchange ("CSPE"). CSPE was responsible for purchasing and marketing Canada's share of the downstream power benefits that resulted from the development of water storage projects in Canada pursuant to a treaty between the U.S. and Canada. The exchange agreements provided for the transfer and assignment of 12.5 percent of such downstream power benefits to the Department and the transfer and assignment thereof, in turn, by the Department to Bonneville. In return, the Department was entitled to specified amounts of energy and capacity from Bonneville. No payments have been required under the agreement since 1998. Power deliveries under the CSPE agreement terminated on March 31, 2003.

Grand Coulee Project Hydroelectric Authority. The Department, in conjunction with the City of Tacoma, Department of Public Utilities, Light Division ("Tacoma"), has power purchase agreements with three Columbia Basin irrigation districts for acquisition of the output from five hydroelectric plants under 40-year contracts expiring between 2022 and 2027. These plants, which utilize water released during the irrigation season, are located along irrigation canals in eastern Washington and have a total installed capacity of approximately 129 MW. The plants generate power only in the summer and thus have no winter peak capability. Plant output and costs are shared equally between the Department and Tacoma. In 2004, under average water conditions, the Department expects to receive 236,863 MWh from the project.

Box Canyon Hydroelectric Plant. The Department purchases power from the Box Canyon Hydroelectric Plant ("Box Canyon") owned and operated by Pend Oreille PUD. The purchase contract, which extends until August 1, 2005, is expected to provide the Department with 79,056 MWh of energy in 2004.

West Point Sewage Treatment Plant Cogeneration. In 1982, the Municipality of Metropolitan Seattle (now part of King County) and the Department executed a contract for the purchase of the electrical output of a cogeneration plant located at the County's West Point Sewage Treatment Plant. The project uses methane gas produced at the treatment plant to provide approximately 1.2 MW of one-hour peak capability from three reciprocating engines. The Department expects to receive 10,541 MWh of energy under the agreement in 2004. The Department is currently discussing with the County various options for changing or extending the current contract, which expires on August 31, 2003.

Wind Generation. An October 2001 agreement with PPM provides for the Department's purchase of energy and associated environmental attributes (such as offsets or emission reduction credits) primarily from the State Line Wind Project in eastern Washington and Oregon. Under the agreement, the Department received wind energy with an aggregate maximum delivery rate of 50 MW per hour from January 1, 2002, through July 31, 2002, and will receive a maximum of 100 MW per hour from August 1, 2002, through December 31, 2021. The Department also expects to receive additional firm energy with an aggregate maximum delivery rate of 25 MW per hour from January 1, 2004, through June 30, 2004, and 50 MW per hour from July 1, 2004, through December 31, 2021, from the State Line Wind Project or other qualifying new wind generation facility. The Department also entered into a ten-year agreement to purchase integration and exchange services from PacifiCorp and a 20-year agreement to sell integration and exchange services to PPM. Energy available from the project is expected to increase from 255,397 MWh in 2003 to 460,185 MWh in 2004.

Exchange with Northern California Power Agency ("NCPA"). The NCPA exchange agreement provides for the Department to deliver 60 MW of capacity and 90,580 MWh of energy to NCPA in the summer. In return, NCPA delivers 46 MW of capacity and 108,696 MWh of energy to the Department in the winter.

Deliveries to NCPA started in 1995 and will continue until the agreement is terminated. Either party has the right to terminate the agreement after May 31, 2014.

Exchange with Tacoma. Since 1963, the Department and Tacoma have coordinated system operations pursuant to an agreement which will remain in effect through October 2003. The agreement provides for the delivery of 37,250 MWh of energy to the Department in August in exchange for the same amount of power in October. Deliveries are shaped uniformly throughout all hours of the respective months. The Department does not expect to renew the agreement when it expires.

Wholesale Market Sales and Purchases

The Department has historically bought and sold energy in wholesale power markets to balance its loads and resources. The amount of energy purchased or sold in the wholesale market has varied with water conditions and with changes in the Department's firm resource base. Prior to 1996, when power available to the Department at critical water levels was roughly equal to its load, the Department typically had surplus power available to sell in the wholesale market when water conditions were above critical levels. With the limitation of its Bonneville purchases in 1996 and the sale of the Centralia Steam Plant in 2000, the Department faced energy deficits at critical water levels, and expected to be a net purchaser of energy in the wholesale market under average water conditions. The Department's new contract with Bonneville, effective October 1, 2001, significantly increased the amount of power available from Bonneville. The acquisition of power from the Klamath Falls Cogeneration Project and the State Line Wind Project further increased the energy resources available to the Department. Demand for power in the Department's service area fell in response to the 2001 rate increases, the Department's encouragement of reduction in usage and the downturn in the local economy. Water conditions were close to normal in the water year beginning October 1, 2001. As a result of all of these factors, the Department had substantial amounts of surplus energy available for sale in the wholesale market in 2002. Sales of surplus power in the wholesale market are expected to continue at high levels over the 2003-2007 period.

The table below displays the actual amounts of energy purchased and sold by the Department in wholesale markets from 2000 through 2002 and the amounts projected to be purchased and sold from 2003 through 2008. In 2000 and 2001, the amount of energy purchased in the wholesale market was substantial due to poor water conditions. The high cost of these purchases reflects high market prices. In 2002, net revenues from wholesale market transactions amounted to $89.6 million. In 2003, net wholesale revenues are expected to reach $128.1 million. The net amount of surplus energy available in 2003 is expected to be 7.6 percent below the 2002 level because of less favorable water conditions. However, the effect of low streamflows is expected to be offset by higher market prices. The average price on the Department's wholesale sales is expected to be $37.08 in 2003, significantly higher than the average price of $24.27 in 2002. Through June 30, 2003, revenue from sales of surplus energy in the wholesale market, net of wholesale purchases, amounted to $67.6 million. The Department has secured an additional $32.1 million of net revenue through forward sales through the end of calendar year 2003. The projection of wholesale market sales and revenue from 2004 through 2007 assumes average water conditions and market prices that average 76 percent of the forward prices for sales at the Mid-Columbia trading hub as of mid-July 2003. Net energy available for sale in the wholesale market is projected to decline from 2004 through 2006 due to load growth in the Department's service area and a reduction in power available under certain existing contracts.

WHOLESALE MARKET SALES AND PURCHASES

	Actual			Projected [1]					
	2000	2001	2002	2003	2004	2005	2006	2007	2008
Wholesale Market Purchases (MWh)	2,571,228	2,411,210	898,613	962,872	33,811	64,660	61,691	53,701	62,074
Cost of Purchases ($000)	$212,402	$518,782	$23,154	$36,006	$973	$1,860	$1,596	$1,673	$2,006
Average Cost ($/MWh)	$82.61	$215.15	$25.77	$37.39	$28.79	$28.77	$25.87	$31.16	$32.32
Wholesale Market Sales (MWh)	2,023,060	468,827	4,647,945	4,425,908	4,655,826	4,384,676	3,713,090	3,788,301	3,672,456
Revenue from Sales ($000)	$103,082	$73,899	$112,796	$164,105	$144,997	$137,230	$116,695	$125,981	$126,561
Average Revenue ($/MWh)	$50.95	$157.63	$24.27	$37.08	$31.14	$31.30	$31.43	$33.26	$34.46
Sales Net of Purchases (MWh)	(548,168)	(1,942,383)	3,749,332	3,463,036	4,622,015	4,320,016	3,651,399	3,734,600	3,610,382
Net Revenue	($109,320)	($444,883)	$89,642	$128,099	$144,024	$135,370	$115,099	$124,308	$124,555

(1) Projections for 2003 reflect actual water conditions through May 31, 2003. Projections for the 2004-2008 period assume average water conditions.

Risk Management

The Department's exposure to risk is managed by a Risk Management Committee ("RMC") consisting of the Superintendent, the Deputy Superintendents for Finance and Administration, Power Management and Generation and the Department's Director of Strategic Planning and Risk Manager. The RMC is responsible for managing both market risk and credit risk.

Market Risk. The RMC meets weekly to review and adjust the Department's near-term and long-term strategy for marketing surplus energy or, in periods of deficit, for purchasing energy to meet load. The Department executes trades in the wholesale market to meet load during periods of resource deficit, to dispose of energy that is surplus to the needs of the Department's retail customers and to optimize the value of the Department's hydroelectric resources by purchasing wholesale energy in off-peak hours, when prices generally are low, and selling energy in the peak hours, when prices are generally higher. The Department does not engage in speculative trading in the wholesale market.

Credit Risk. The Department's Credit Committee, which reports to the RMC, consists of the Deputy Superintendent for Power Management and the Department's Finance Director, Director of Customer Accounts and Risk Manager. The Credit Committee meets monthly to manage the credit risk associated with the Department's marketing activities. Finance Division staff review the creditworthiness of counterparties with which the Department trades power in the wholesale market and recommends credit limits for each counterparty. Where appropriate, credit enhancements are recommended for counterparties that do not meet standards of creditworthiness adopted by the Credit Committee. Finance and Power Management staff monitor trading activity to ensure that credit limits established by the Credit Committee are not exceeded and provide status reports to the Credit Committee.

Transmission

Department-Owned Transmission. The Department operates 656 miles of transmission facilities. The principal transmission line transmits power from the Skagit Project to the Department's service area. In 1994, the Department signed an agreement with Bonneville for the acquisition of ownership rights to 160 MW of transmission capability over Bonneville's share of the Third AC Intertie, which connects the Northwest region with California and the Southwest. The benefits from this investment include avoidance of Bonneville's transmission charges associated with power sales and exchanges over the Intertie and the ability to enter into long-term firm contracts with out-of-state utilities. The Oregon Department of Revenue has initiated litigation to collect a property tax on the Department's capacity rights in the Third AC Intertie. The potential liability is about $500,000 per year. Summary judgment motions were argued in the Oregon Tax Court in May 2003. An appeal to the Oregon Supreme Court is likely to follow the Tax Court's disposition of the case, and an appeal to the United States Supreme Court is possible.

Regional Transmission Organizations. In 1999, FERC issued its Order 2000, which mandated the formation of regional transmission organizations ("RTOs") and set forth various standards for their organization and operation. In response, Bonneville and nine investor-owned utilities in the Pacific Northwest initiated efforts to create "RTO West," a Washington non-profit corporation, to function as the operator of the principal transmission facilities in the Pacific Northwest and provide transmission services under standardized tariffs. The Department cannot predict the ultimate outcome of efforts to establish RTO West or the potential effects on the Department's operations and finances. See "Change in the Electric Utility Industry."

Transmission Arrangements with Bonneville. Contracts with Bonneville provide the Department with 1,962 MW of transmission capacity under a point-to-point ("PTP") transmission service agreement for the period from October 1, 2001, through July 31, 2025. The Department's rights under the current PTP contract are expected to be preserved under RTO West. However, the rates that will apply to services provided by RTO West are uncertain, as are the rates likely to be charged by Bonneville if the formation of RTO West is delayed or abandoned. In its financial forecast, the Department has assumed that wheeling costs will increase by 22 percent from 2004 through 2008.

Power supplied to the Department by B.C. Hydro under the High Ross Agreement is transmitted over Bonneville's lines under a second PTP transmission service agreement extending through 2005. The High

Ross PTP contract was assigned to B.C. Hydro in 1999. B.C. Hydro in turn reassigned the contract to the British Columbia Power Exchange Corporation ("Powerex"). Under the assignment agreement provisions, Powerex pays Bonneville directly for all costs associated with the PTP contract. The Department expects to renew this PTP contract with Bonneville in 2006 for at least an additional ten-year term, and simultaneously to renew the assignment arrangement with B.C. Hydro for the same term. See "Power Resources—The Department's Resources."

Additional purchases of transmission on a nonfirm basis may be required in the future in order to accommodate the Department's sales of power in the wholesale market during the spring runoff.

Other Transmission Contracts. The Department also transmits power under contracts with Idaho Power for the transmission of power from the Lucky Peak Project, with Avista for transmission of power from the Grand Coulee Project Hydroelectric Authority; with Puget Sound Energy for transmission of power from the Cedar Falls and South Fork Tolt Projects, and with other utilities.

Conservation

The Department has pursued a policy of managing as well as meeting energy demand. As a result of the "Energy 1990" study, prepared in 1976, the City decided to pursue conservation as an alternative to participating in Energy Northwest's Projects Nos. 4 and 5. During the 1980s, single-family residential measures dominated the Department's conservation program. Conservation incentive programs in the commercial, industrial and multifamily sectors were added in the 1990s. Because commercial and industrial measures are more cost-effective, the majority of new energy savings acquired in recent years has come from these sectors, a trend that is projected to continue into the future. Since 1977, the Department has achieved almost 100.4 average MW of energy savings through conservation.

The 2000 Strategic Resources Plan called for the Department to accelerate the pace of energy savings through conservation. In the spring of 2001, a work plan was developed which increased the targeted level of energy savings to be achieved annually through conservation programs from six average MW to nine average MW per year. To meet this higher target, the work plan called for the Department to continue to operate its core conservation initiatives for all customer groups while adding some new programs and services to address service gaps.

The new power sales contract with Bonneville that took effect on October 1, 2001, provides a credit of $0.50 per MWh against the amounts payable under Bonneville's rate schedules for investments in conservation and renewable resources. The Department estimates that this credit will reduce payments to Bonneville by $2.2 million per year.

Under a March 2002 agreement with Bonneville, Bonneville has paid the Department $27 million for conservation savings to be achieved over the period from October 1, 2001, through September 30, 2003. As part of this agreement, the Department's purchases of power from Bonneville under the Block product have been reduced by 9.8 average MW from April 1, 2002, through September 30, 2002, and by 19.1 average MW from October 1, 2002, through September 30, 2011. The Department and Bonneville recently signed a letter of intent to execute an amendment to the March 2002 agreement extending funding for another three years. Under the amendment, Bonneville would provide an additional $24 million of funding to purchase 7.25 average MW per year of conservation savings over the period from October 1, 2003, through September 30, 2006, with concomitant reductions of 7.25 average MW annually in the Department's purchases of Block power from Bonneville.